

# The Role of Gas Processing in the Natural-Gas Value Chain

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## Abstract

Production of natural gas is the first step in the value chain that takes gas from the reservoir to the customer (typically at a burner-tip). An integral and essential part of this value chain is the midstream sector. Midstream refers to the gathering, compression, and processing functions required between the wellhead and the transmission system.

Midstream assets and activities are found at any location where natural gas is produced, transported, or sold. For example, in North America the first gas-gathering and -processing facilities were installed circa 1910, primarily to extract casinghead gasoline from solution gas produced with crude oil. In Europe, the midstream sector developed in the 1960s with the discovery of large nonassociated-gas fields in the southern North Sea and in the Groningen field in The Netherlands. Industry development in the Middle East was spurred by the huge associated-gas-gathering and -processing projects initiated by Saudi Aramco in the late 1970s and early 1980s. **Fig. 1** shows a schematic of the gas-gathering and -processing facilities in the total production system. This article discusses the gas-processing portion of the midstream

sector, with the primary objective of providing technical professionals on the upstream side of the industry some insight into the midstream sector.

## Gas Conditioning and Sales-Gas Specifications

One of the principal objectives of the gas-processing industry is to condition the gas for sale. Natural gas must meet several specifications before it can enter the transmission system. Historically, these specifications have been referred to as “sales-gas specifications,” but in many areas they are really transportation specifications. This is because gas from many producers will be transported in “open-access” gas pipelines to the gas buyers along the pipe route. The sales agreement may be between the producer and the buyer, but there is no guarantee the buyer will actually receive the producer’s molecules. In North America, for example, producers negotiate transportation agreements with pipelines and must meet the shipper’s transportation specifications before the pipeline operator will accept the gas. These specifications are set out in the tariff the shipper files with the US Federal Energy Regulatory Commission. **Table 1** shows some example sales/transportation specifications in North America and Europe.

The water- and hydrocarbon-dewpoint specifications are a function of ambient temperature. In equatorial climates, it is not unusual for these dewpoint specifications to range from 32 to 50°F. Water specifications can be written as a water concentration (e.g., lbm H<sub>2</sub>O/MMscf of gas) or in terms of a water dewpoint. If a water dewpoint is specified in the contract, it must be stated at a reference pressure (P), which typically is the pipeline operating pressure. Generally, the conversion of water content to water dewpoint (and vice versa) is done by use of a water-content correlation. A commonly used correlation is Fig. 20-4 in the *GPSA Engineering Data Book* (Gas Processors Suppliers Association 2004).

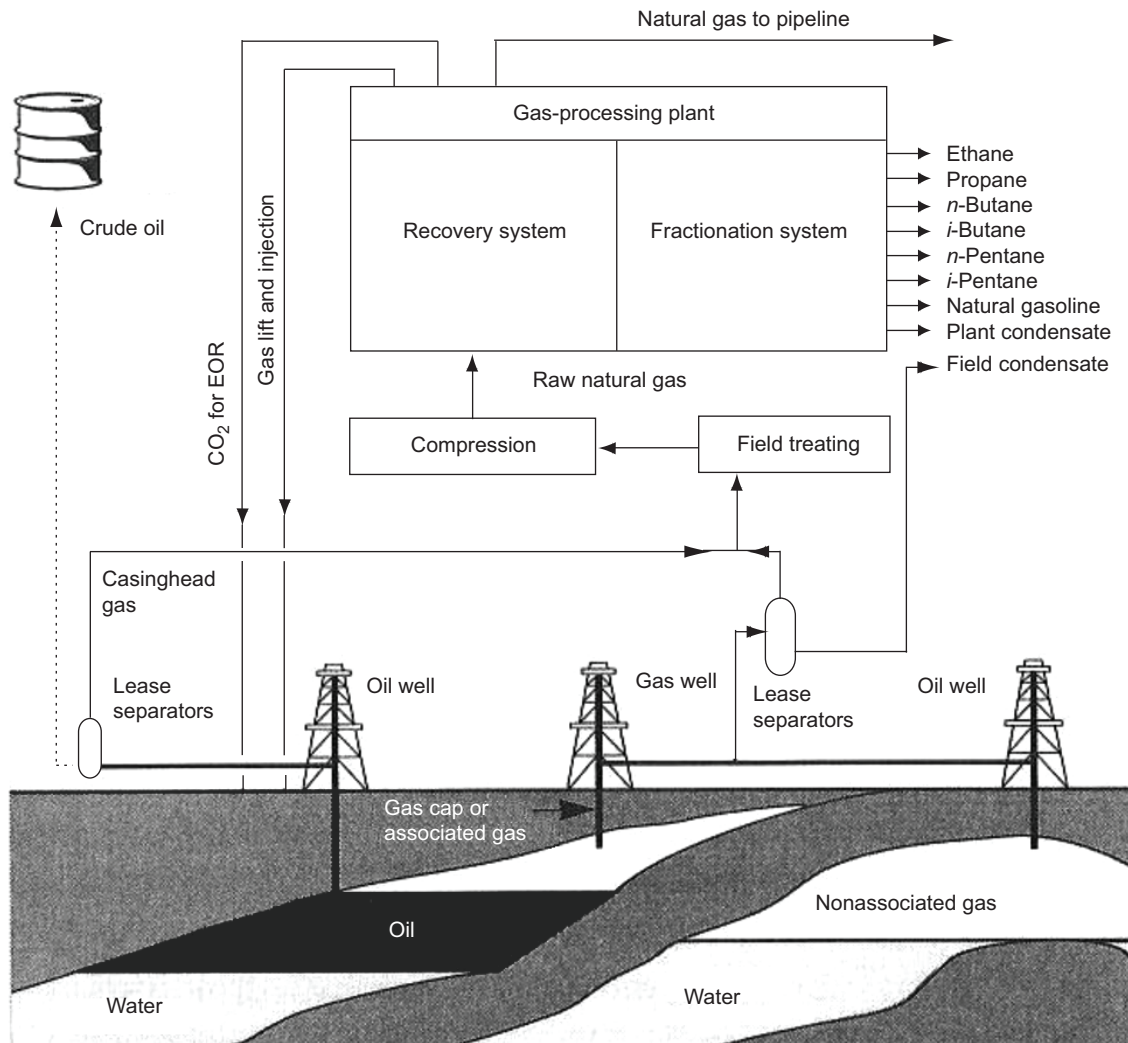
Hydrocarbon dewpoint (HCDP) also must be referenced to a pressure. In many contracts, it is required that the HCDP be met at any pressure in the transmission system. Because the highest dewpoint temperature will be at the cricondentherm pressure, this specification often is considered a cricondentherm specification.



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and consulting services to many international oil and gas companies. During that time, Hubbard served in several capacities including Chairman of the Board. He has more than 37 years’ experience in oil and gas facilities worldwide. Hubbard also worked for Texaco during 1972–80, where he held various engineering and management positions. He has authored several papers in the area of natural-gas-production and -processing facilities and has presented many talks at conferences and technical meetings worldwide. Hubbard holds a BS degree in chemical engineering from Kansas State University and an MBA degree from Tulane University. He has chaired the SPE Facility Engineering Committee and is a member of the executive committee for the Oklahoma City SPE Section.

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**Fig. 1—Gas gathering and processing in the total production system (Cannon 1993).**

Concentrations of nonhydrocarbon contaminants vary. For gas that is delivered into a common transmission system that serves many customers, these specifications are nonnegotiable. For gas delivered to a few customers in a dedicated pipeline, the contaminant specifications are more flexible. There are several examples of contracts where the allowable concentration of CO<sub>2</sub>, H<sub>2</sub>S, and/or N<sub>2</sub> is substantially higher than the values in Table 1. This flexibility can significantly lower gas-processing costs and is particularly important for components such as mercaptans and sulfur species other than H<sub>2</sub>S because these can be difficult to remove from natural gas.

The heating-value specifications vary depending on the market served by the transmission system and almost always refer to the higher heating value. Customers on the transmission grid expect heating values to fall in a range compatible with their combustion equipment. In general, the heating-value specifications in the US are lower than in most European and Asian markets. Primarily, this is because

almost all of the gas sold in the US has undergone deep natural-gas-liquid (NGL) extraction in a gas-processing plant.

Wobbe number is a measure of heat release at a burner tip for a fixed pressure drop across the burner orifice. It is preferred in many markets because it is a better measure of fuel interchangeability than heating value alone. It is widely specified in European contracts, sometimes in lieu of the heating-value specification. Wobbe number is rarely specified in North American contracts, but there has been considerable interest in incorporating it into transportation contracts for transmission systems that can receive imported liquefied natural gas (LNG) (Kuipers 2004) because most LNG imported into the US has a significantly higher heating value than the gas in the grid.

### NGL Extraction

In the case of gas conditioning, the objective is to meet sales-gas specifications only. NGLs are removed only to the extent required to meet the HCDP and heating-value specifications,

**TABLE 1—EXAMPLE SALES-GAS/TRANSPORTATION SPECIFICATIONS**

Specification	North America	Europe
Water content (North America)	4–7 lbm H <sub>2</sub> O/MMscf of gas	–10 to –12°C at 7000 kPa
Water dewpoint (Europe)		
Hydrocarbon dewpoint	14–40°F at specified P	0 to –5°C at P < 7000 kPa
CO <sub>2</sub> concentration	1–3 mol%	2–3 mol%
N <sub>2</sub>	2–3 mol%*	2–3 mol%*
Total inerts	3–5 mol%*	NA
H <sub>2</sub> S	0.25–1.0 grain/100 scf	5–7 mg/Nm <sup>3</sup>
Total S	0.5–2.0 grain/100 scf	120–150 mg/Nm <sup>3</sup>
Mercaptans	0.25–1.0 grain/100 scf*	6–15 mg/Nm
Oxygen	10–2,000 ppm (mol)	1,000–5,000 ppm (mol)
Heating value	950–1,200 Btu/scf	40–46 MJ/Nm <sup>3</sup>
Wobbe number	NA	51–56 MJ/Nm <sup>3</sup>

NA = not applicable  
\* = often not specified

which typically requires only minimal extraction of C<sub>5</sub>+ components. In locations where NGL markets, transportation, and storage infrastructure exist, it may be desirable to extract NGLs from the gas for economic reasons. **Table 2** shows NGL products and markets.

NGL extraction can increase revenue from the produced-gas stream. NGLs typically compete with crude-oil-derived products, so their prices tend to follow crude-oil prices. When, on an energy-equivalent basis, the price of crude oil exceeds the price of natural gas, NGL extraction is often economically viable. When crude-oil and natural-gas prices are the same, NGL extraction may be uneconomic.

**Fig. 2** shows crude-oil, natural-gas, and propane prices for the period 1985–2008. Prices were taken from the US Department of Energy, Energy Information Agency, and they represent the spot price for West Texas Intermediate crude oil at Cushing, Oklahoma; average US wellhead price for

natural gas; and spot price for propane at Mt. Belvieu, Texas. Prices for other NGL products are not publicly posted.

The difference between crude-oil and propane prices and natural-gas prices represents the gross profit margin for NGL extraction, often referred to as the “frac spread” in the US. The value of the NGL component in the gas stream is referred to as “shrinkage” because it represents revenue forgone (energy value transferred from the gas stream to the liquid stream) if NGLs are extracted from the gas.

Three important conclusions can be taken from Fig. 2. First, on an energy-equivalent basis, the price of propane correlates very well with the price of crude oil. This is true of other NGL products as well, particularly butanes and natural gasoline. Second, NGL-extraction margins were relatively stable in the late 1980s and through much of the 1990s. This changed at the beginning of this decade, and, since 2000, the volatility in extraction margins has been extremely high. Third, it is

**TABLE 2—NGL PRODUCTS AND MARKETS**

NGL Component	Market Use
Ethane (C <sub>2</sub> )	Petrochemical feedstock for manufacture of ethylene
Propane (C <sub>3</sub> )*	Petrochemical feedstock for manufacture of propylene and ethylene Residential and commercial fuel in rural areas, transportation fuel, and cooking grills
Isobutane ( <i>i</i> -C <sub>4</sub> )	Refinery feedstock to alkylation unit, methyl-tertiary-butyl-ether feedstock Fuel use as a component in LPG
Normal butane ( <i>n</i> -C <sub>4</sub> )	Gasoline blending, petrochemical feedstock for manufacture of light olefins Fuel use as a component in LPG, isomerized to <i>i</i> -butane
Natural Gasoline (C <sub>5</sub> +)**	Refinery feedstock to reformer or isomerization unit Petrochemical feedstock for manufacture of light olefins

\* Often sold as liquefied petroleum gas (LPG). LPG can be C<sub>3</sub>, C<sub>3</sub>–C<sub>4</sub> mix, or predominantly C<sub>4</sub>.  
\*\* Natural gasoline is a North American term, also referred to as light naphtha or condensate in other regions.

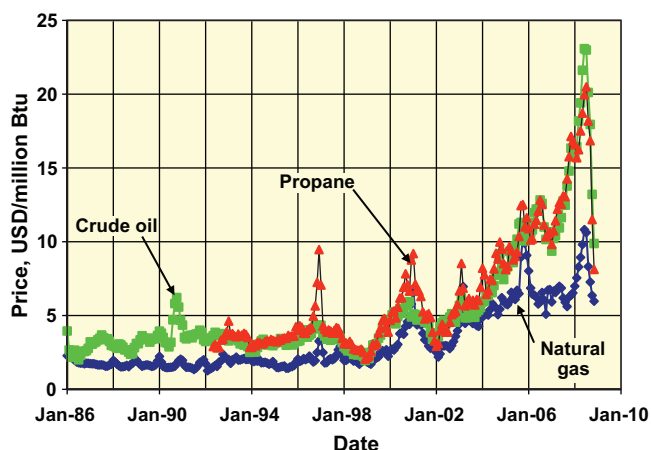


Fig. 2—U.S. energy prices 1986–2008.

possible to identify those times during which extraction was marginally economic or uneconomic (winters of 1998–99, 2000–01, and 2001–02 and most of 2003) as well as those times during which extraction margins were very attractive (2004–08). In fact, with the exception of the few months following Hurricane Katrina, the period 2005 through the first half of 2008 represents the most profitable period ever.

Shrinkage represents the largest cost of NGL extraction, but gas processors also incur other costs. Most gas-processing plants in North America produce a mixed-NGL stream (C<sub>2</sub>+ or C<sub>3</sub>+). These streams must be transported to a fractionation facility, where the NGLs are separated into marketable components. The gas processor must pay for this service. In addition, NGL-extraction plants also must cover operating costs and earn a return on investment. Worldwide, NGL production is a significant business accounting for approximately 7 million B/D of hydrocarbon liquids in 2007. This represents approximately 10% of world crude-oil production. Table 3 shows NGL production by country for 2007.

**Processing Schemes**

Fig. 3 is a block flow diagram for a gas-processing facility. Each box represents a different section of the plant and may include one or more processes. The actual processes used depend on the feed-gas composition and the sales specifications for both the gas and liquid products. The following is a description of process schemes used in a gas-processing plant.

**Conditioning.** Conditioning generally refers to the removal of gas contaminants such as H<sub>2</sub>O, H<sub>2</sub>S and other sulfur species, CO<sub>2</sub>, and mercury. The level of removal can be dictated by the sales-gas specifications, NGL-product specifications, or processing requirements. Gas dehydration is the most commonly used process in the midstream sector. Three processes dominate.

- Absorption: This process almost always refers to glycol dehydration. The most common solvent is triethylene glycol. Glycol dehydration is used widely for gas dehydration in production and pipeline applications, but it also is used

TABLE 3—2007 NGL PRODUCTION BY COUNTRY (SPECIAL REPORT 2008)

Country	Production, million B/D	% of Total
United States	1,815	26.0
Saudi Arabia	882	12.6
Canada	774	11.1
Mexico	515	7.4
Kuwait	445	6.4
Australia	260	3.7
Russia/FSU	217	3.1
UAE	214	3.1
Venezuela	174	2.5
India	156	2.2
Norway	148	2.1
Rest of World	1,385	19.8
Total	6,986	100.0

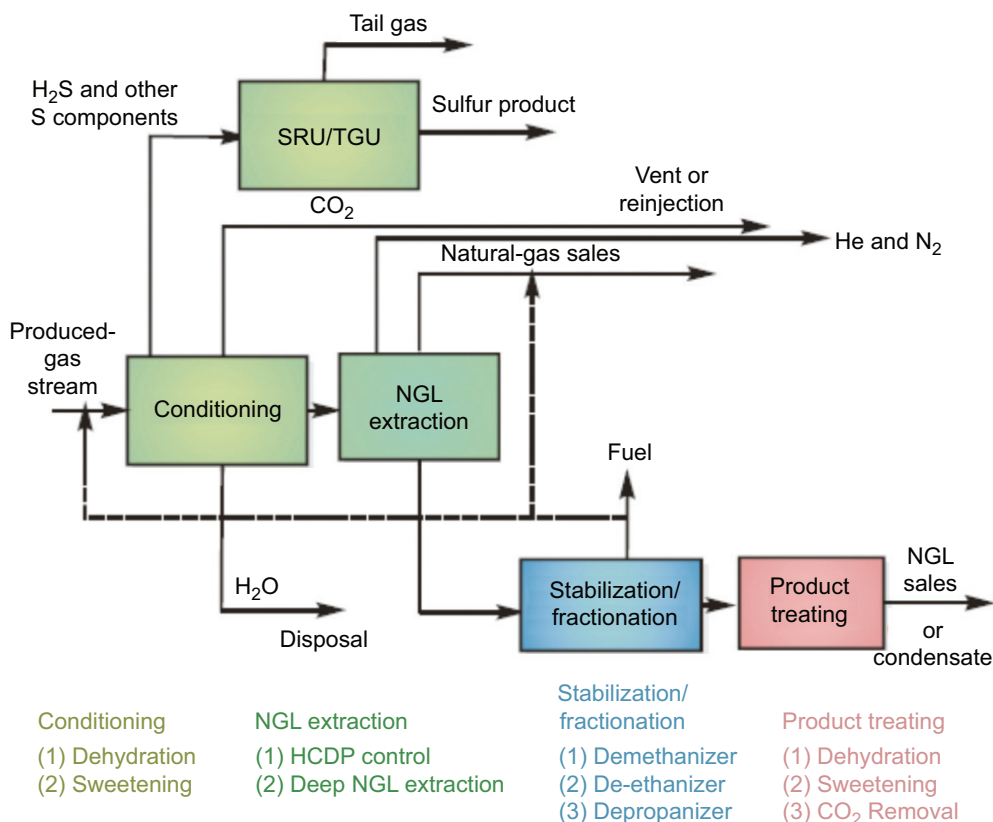
in process applications in which the minimum processing temperature is higher than -30 to -40°F

- Adsorption: This process is most common when the processing temperature is below -40°F and is the dominant dehydration process in deep-recovery NGL-extraction plants as well as LNG plants. Typically, the desiccant is a molecular sieve, but silica gel sometimes is used in gas-dewpointing applications. Adsorption is capable of achieving water dew-points below -150°F

- Condensation and Inhibition: This process uses the refrigeration in the NGL-extraction box to condense water as well as hydrocarbons. Hydrate formation is prevented by the injection of an inhibitor, typically monoethylene glycol or methanol. The water-inhibitor solution is separated from the condensed hydrocarbons in a three-phase separator, regenerated, and reinjected into the feed gas, typically upstream of a heat exchanger.

H<sub>2</sub>S and CO<sub>2</sub> are referred to as acid-gas components because they dissolve in water to form a weak acid. There are several processes that can be used to remove these components from natural gas. Several are proprietary and require a license. The following processes are the most common.

- Chemical Absorption: This is the most common process used for H<sub>2</sub>S and CO<sub>2</sub> removal from natural gas. Amines are water soluble, organic, nitrogen compounds that form a basic solution in water. They react reversibly with acid-gas components to form a water-soluble salt. The acid/base reaction is reversed in the regenerator at low-pressure, high-temperature conditions, and the acid gas is removed at the regenerator overhead while the amine solution is removed at the bottom and recirculated to the absorber. Some of the common amines used are monoethanol amine, diethanol amine, methyl diethanol amine (MDEA), diglycol amine, and diisopropanol amine. With the exception of MDEA,



**Fig. 3—Gas-processing block diagram. SRU=sulfur-rejection unit, TGU=tail-gas unit. (Reproduced with permission, John M. Campbell and Company, 2009.)**

amines are generally not selective and will remove both CO<sub>2</sub> and H<sub>2</sub>S from the gas. MDEA will preferentially absorb H<sub>2</sub>S over CO<sub>2</sub> because of a faster reaction time. Amines frequently are “engineered” to increase selectivity and/or absorption capacity. Most amine solutions are ineffective in removing other sulfur species such as mercaptans, carbonyl sulfide (COS), CS<sub>2</sub>, and others.

- Physical Absorption: Physical solvents absorb acid-gas components by solubility in the solvent (i.e., no chemical reaction takes place). In general, physical solvents are used in applications where the partial pressure of the acid-gas components in the feed gas is high and/or removal of other sulfur species is required. Relative to amines, physical solvents are less corrosive and require less energy to regenerate, but tend to coabsorb heavy hydrocarbons. In almost all cases, physical solvents are proprietary processes and require a licensing agreement.

- Fixed Bed: H<sub>2</sub>S and other sulfur species can be removed from gas by adsorption or reaction with a solid material such as molecular sieve or a metallic oxide. These processes are limited to sulfur-removal applications and in general are applied when the amount of sulfur to be removed is small, less than 100 lbm/D.

- Membranes: Membranes are used widely for the removal of CO<sub>2</sub> from natural gas. Membranes generally are not effective for the removal of H<sub>2</sub>S and other sulfur species because of the very low outlet concentrations required.

- Other: Several other process schemes can be used to remove acid-gas components from natural gas. These processes include removal of H<sub>2</sub>S (liquid scavengers for the removal of H<sub>2</sub>S and other sulfur species) and removal of CO<sub>2</sub>. These schemes may be the optimal choice in specific applications, but in general represent a small percentage of total acid-gas-removal installations.

Another component frequently removed from natural gas in the conditioning section is mercury. Mercury is corrosive to aluminum heat exchangers that are widely used in low-temperature processing applications, such as deep NGL extraction and LNG liquefaction. The most common process for removing mercury is chemical reaction with sulfur that has been impregnated into a solid matrix such as activated carbon or activated alumina.

**Acid-Gas Disposition.** In amine, physical-solvent, and membrane processes, the acid gas is recovered as a low-pressure-gas stream. If this stream is CO<sub>2</sub> and contains no sulfur compounds, it is either vented to atmosphere or reinjected into the subsurface. In miscible-flood projects, such as those in the west Texas Permian Basin in the US, the CO<sub>2</sub> is recovered and reinjected into the producing reservoir to increase oil recovery.

When the recovered acid-gas stream contains sulfur compounds, venting or flaring typically is not an option. In

these cases, the acid gas is reinjected into the subsurface for enhanced oil recovery (EOR) or for sequestration. When the acid-gas stream is substantially  $H_2S$ , it frequently is sent to an SRU, where sulfur species are converted to elemental sulfur.

**NGL Extraction.** As discussed previously, liquid hydrocarbons can be removed from the gas for the purpose of conditioning the gas for sale or to increase revenue by selling NGLs into higher-priced markets than those for natural gas. The most common NGL-extraction processes involve refrigeration of the gas.

- **Mechanical Refrigeration:** Mechanical (or external) refrigeration involves the use of a refrigerant to chill the gas to low temperatures for the purpose of condensing NGLs. This process is used widely in gas-conditioning applications (e.g., HCDP control), but it also is used in NGL-recovery applications as the primary refrigeration option or in conjunction with another refrigeration option. The most common refrigerant is propane, but commercial refrigerants or ammonia is used also. In general, the minimum processing temperature is limited to the atmospheric boiling point of the refrigerant,  $-30$  to  $-40^\circ F$  for the most popular refrigerants.

- **Valve Expansion:** This process relies on the cooling from a Joule-Thomson (J-T) expansion and often is referred to as a J-T plant. Other terms applied to the process are low-temperature separation and low-temperature extraction. The advantages of this process are simplicity and low cost. The primary drawback is the pressure drop that occurs across the valve, which often ranges from 500 to 1,000 psia. This process typically is used in HCDP-control applications on high-pressure nonassociated gas in which the flowing tubing pressures are sufficiently high to eliminate the need for compression.

- **Turboexpanders:** Turboexpanders are single-stage radial-inflow expansion turbines that theoretically approach a constant-entropy expansion (rather than constant-enthalpy expansion that occurs across valves). Much lower outlet temperatures are achieved for the same pressure drop compared to J-T expansion. Turboexpanders are the most common process used worldwide for deep NGL extraction, with minimum temperatures below  $-150^\circ F$  achieved routinely. In addition, this process is used for gas-conditioning applications (HCDP control). In HCDP applications, the required pressure drop across the expander is substantially less than that required across a J-T valve, which can result in lower compression costs over the life of the field.

- **Other:** Before 1970, the refrigerated-lean-oil process was the dominant NGL-extraction option in North America. This process uses a gasoline-like solvent to absorb NGLs from the gas at low temperature. High recoveries of NGLs are possible. A few lean-oil plants are still used in the US and Canada, but they have been largely replaced by turboexpander processes. Another process is adsorption by use of silica gel. Silica gel has an affinity for  $C_5+$  hydrocarbons as well as for water. It can be used to meet water- and hydrocarbon-dewpoint specifications simultaneously. Common applications include conditioning of gas removed from gas-storage reservoirs and

conditioning of high-pressure gas for which phase behavior limits the effectiveness of refrigeration processes.

Occasionally, the feed gas has a nitrogen concentration that exceeds the sales-gas specification or contains sufficient helium to justify its recovery from the gas. When required, nitrogen rejection and/or helium recovery often is done in the NGL-extraction section of the process. A nitrogen/helium-rich stream that contains significant methane is taken from the process, and the methane is separated from the nitrogen and/or helium by cryogenic fractionation or membranes. Alternatively, for smaller gas-flow rates, nitrogen can be removed upstream of the NGL-extraction section with pressure-swing adsorption.

**Stabilization.** Hydrocarbon liquids condensed in the NGL-extraction section of a plant contain significant amounts of methane and light NGLs. These light contaminants must be removed before the liquid product can be sold. In deep-NGL-extraction plants for which the NGL-product stream is  $C_2+$ , the only light-hydrocarbon contaminant that must be removed is methane, and this is done in a distillation column referred to as a demethanizer. If there is no market for ethane, and the lightest NGL product recovered from the gas is propane (NGL product is  $C_3+$ ), then the distillation column is a de-ethanizer.

For HCDP applications and for those applications in which it is desirable to recover  $C_5+$  components from an associated gas to spike into the crude stream, the level of stabilization is set by the vapor-pressure specification of the liquid product. In such cases, the NGL-product stream might be stabilized in a distillation column similar to a condensate stabilizer or stabilized along with the crude oil in the separator flash system.

Flash gas from the stabilization section of the plant typically is routed to the sales-gas stream in deep-NGL-extraction processes. For systems in which the NGL product is  $C_5+$ , the stabilizer flash gas typically is used as fuel gas or is recycled to the feed gas.

**Product Treating.** Product treating refers to a final processing step required to meet the NGL-product specifications. Product treating generally falls in two broad categories.

- **$CO_2$  Removal From  $C_2+$  Streams:** In the US, the maximum allowable concentration of  $CO_2$  in a  $C_2+$  NGL stream often is less than 500 ppm (by weight). If the feed gas to a gas-processing plant contains  $CO_2$ , it would be highly unlikely that the NGL-product stream would meet the sales specification because the  $CO_2$  in the feed gas tends to concentrate in the NGL stream rather than in the sales gas. This situation requires removal of  $CO_2$  from the NGL-product stream, and the most common process used is an amine system. The amine and NGL liquids are contacted in a special column frequently referred to as a liquid treater.

- **$H_2S$ /Sulfur-Compound Removal:** As was the case with  $CO_2$ ,  $H_2S$  and sulfur compounds (e.g., mercaptans and COS) tend to concentrate in the NGL stream rather than in the sales gas. It is not unusual for the sales-gas stream leaving a gas-processing plant to meet sales-gas specifications with

regard to sulfur species, but the NGL stream does not. In these cases, sulfur compounds must be removed from the NGLs. Several processes are used, depending on the sulfur species present in the NGL stream, but amine, molecular sieve, and caustic-wash systems are popular options.

### Conclusions

Gas processing is a critical step in the natural-gas value chain. At a minimum, the gas must be processed to meet sales-gas specifications, and in many cases NGLs extracted from the gas provide a significant revenue stream to the producer.

Gas-processing facilities are more complex than production facilities, and their design and operation is far more dependent on the gas composition, flow rate, temperature, and pressure than most production facilities. In many cases, communication between reservoir/production engineers and the facility/process engineers who must design the gas-processing plant is limited. This situation can lead to “gaps in knowledge” on both sides of the system, resulting in inadequate designs, higher capital and operating costs, and reduced production rates.

A second, critical, factor at the production/processing interface is the negotiation of the gas-sales-contract terms. Small changes in a gas-sales specification can have a large effect on the cost and complexity of the gas-processing facility. This is particularly true for trace contaminants in the natural gas. Frequently, the negotiations between the buyer and seller focus on gas-quantity rather than gas-quality issues. The result can be quality specifications that

are unclear and/or difficult or impossible to meet. From the seller's perspective, it is critical that someone familiar with the complexities of gas processing be involved in the negotiation of gas-sales agreements.

### Future Developments

Future natural-gas developments, particularly outside North America, increasingly will target high-pressure, high-temperature reservoirs containing gases with significant concentrations of contaminants such as Hg, CO<sub>2</sub>, N<sub>2</sub>, H<sub>2</sub>S, and other sulfur species. The challenge for the midstream industry will be to process these gases economically, in a safe manner, and with minimal environmental effect. Efficient removal and disposal of gas contaminants will be a critical aspect of these projects, and most of the new-technology developments in gas processing will focus on this area. **JPT**

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## PEOPLE

**Brian Coffman**, SPE, will help lead business development efforts in Maxwell Drummond International's Calgary office. He is managing consultant for Maxwell Drummond International. Before joining Maxwell Drummond International, he held various human resource positions for BHP Billiton. Coffman has more than 10 years of experience in executive search and human resources.



and a PhD degree in petroleum engineering from the University of Tulsa.

**J.C. Cunha**, SPE, was named manager of operations for Petrobras America. He is a former professor of petroleum engineering at the University of Alberta. Cunha is chairperson of the *JPT* Editorial Committee. He earned a degree in civil engineering from Juiz de Fora Federal University, an MSc degree in petroleum engineering from Ouro Preto University,

**Karl Ruud**, SPE, was named president and chief executive officer of Akita Drilling. Before this appointment, he was president and chief operating officer for Akita Drilling. Ruud has drilling experience internationally and has been with Akita since the formation of the company.

**Kevin Strachan**, SPE, was named group financial controller for the Ferguson Group. Before this appointment, he was chief financial officer for Chantry Networks.

### MEMBER DEATHS

- Robert J. Doran**, Sydney
- Larry H. Flak**, Conroe, Texas